BEFORE THE
PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA
DOCKET NO. 2020-3-E

In the Matter of:	)	
Annual Review of Base Rates	)	**DIRECT TESTIMONY OF**
for Fuel Costs for	)	**JOHN A. VERDERAME FOR**
Duke Energy Carolinas, LLC, Decreasing	)	**DUKE ENERGY CAROLINAS, LLC**
Residential and Non-Residential Rates	)	

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John A. Verderame. My business address is 526 South Church Street, Charlotte, North Carolina 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am Vice President, Fuels & Systems Optimization for Duke Energy Corporation ("Duke Energy"). In that capacity, I lead the organization responsible for the purchase and delivery of coal, natural gas, fuel oil, and reagents to Duke Energy's regulated generation fleet, including Duke Energy Carolinas, LLC ("DEC," or the "Company") and Duke Energy Progress, LLC ("DEP") (collectively, the "Companies"). In addition, I manage the fleet's power trading, system optimization, energy supply analytics, and contract administration functions.

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Arts degree in Economics from the University of Rochester in 1983, and a Master's in Business Administration in Finance from Rutgers University in 1985. I have worked in the energy industry for 19 years. Prior to that, from 1986 to 2001, I was a Vice President in the United States (US) Government Bond Trading Groups at the Chase Manhattan Bank and Cantor Fitzgerald. My responsibilities as a US Government Securities Trader included acting as the Firm's market maker in US Government Treasury securities. I joined Progress Energy, in 2001, as a Real-Time Energy Trader. My responsibilities as a Real-Time Energy Trader included managing the real-time energy position of the Progress Energy regulated utilities. In 2005, I was promoted to Manager of the

Power Trading group. My role as manager included responsibility for the short-term capacity and energy position of the Progress Energy regulated utilities in the Carolinas and Florida.

In 2012, upon consummation of the merger between Duke Energy and Progress Energy, Progress Energy became DEP and I was named Managing Director, Trading and Dispatch. As Managing Director, Trading and Dispatch I was responsible for Power and Natural Gas Trading and Generation Dispatch on behalf of Duke Energy's regulated utilities in the Carolinas, Florida, Indiana, Ohio, and Kentucky. I assumed my current position in November 2019.

Q. HAVE YOU TESTIFIED OR SUBMITTED TESTIMONY BEFORE THIS COMMISSION IN ANY PRIOR PROCEEDINGS?

A. Yes. I testified before the Public Service Commission of South Carolina ("Commission") in DEP's 2020 fuel and environmental cost proceeding in Docket No. 2020-1-E.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to describe DEC's fossil fuel purchasing practices, provide fossil fuel costs for the period June 1, 2019 through May 31, 2020 ("review period") versus June 1, 2018 through May 31, 2019 ("prior review period"), and describe changes forthcoming in the period of October 1, 2020 through September 30, 2021 ("billing period").

Q. YOUR TESTIMONY INCLUDES TWO EXHIBITS. WERE THESE EXHIBITS PREPARED BY YOU OR AT YOUR DIRECTION AND UNDER YOUR SUPERVISION?

A. Yes. These exhibits were prepared at my direction and under my supervision, and consist of Verderame Exhibit 1, which summarizes the Company's Fossil Fuel Procurement Practices, and Verderame Exhibit 2, which summarizes total monthly natural gas purchases and monthly contract and spot coal purchases during the review period and the prior review period.

Q. PLEASE PROVIDE A SUMMARY OF DEC'S FOSSIL FUEL PROCUREMENT PRACTICES.

A. A summary of the Company's fossil fuel procurement practices is set out in Verderame Exhibit 1.

Q. HOW DOES THE COMPANY OPERATE ITS PORTFOLIO OF GENERATION ASSETS TO RELIABLY AND ECONOMICALLY SERVE ITS CUSTOMERS?

A. Both DEC and DEP utilize the same process to ensure that the assets of the Companies are reliably and economically available to serve their respective customers. To that end, both companies consider factors that include, but are not limited to, the latest forecasted fuel prices, transportation rates, planned maintenance and refueling outages at the generating units, generating unit performance parameters, and expected market conditions associated with power purchases and off-system sales opportunities in order to determine the most economic and reliable means of serving their customers.

Q. PLEASE DESCRIBE DEC'S DELIVERED COST OF COAL AND NATURAL GAS DURING THE REVIEW PERIOD.

A. The Company's average delivered cost of coal per ton for the review period was $85.33 per ton, compared to $84.19 per ton in the prior review period, representing an increase of approximately 1 percent. The cost of delivered coal is inclusive of the costs related to the buyout of coal contract obligations which occurred in April 2020 as well as an average transportation cost of $29.92 per ton in the review period, compared to $31.49 per ton in the prior review period, representing a decrease of approximately 5 percent. The Company's average price of gas purchased for the review period was $3.06 per Million British Thermal Units ("MBtu"), compared to $3.60 per million MBtu in the prior review period, representing a decrease of approximately 15 percent. The cost of gas is inclusive of gas supply, transportation, storage and financial hedging.

DEC's coal burn for the review period was 7.2 million tons, compared to a coal burn of 7.5 million tons in the prior review period, representing a decrease of 5 percent. The Company's natural gas burn for the review period was 128.5 million MBtu compared to a gas burn of 137.0 million MBtu in the prior review period, representing a decrease of approximately 6 percent. The net decrease in DEC's overall natural gas burn was primarily driven by gas to coal switching as a result of the new coal rail transportation rate that went into effect March 1, 2019 coupled with decreased demand resulting from the COVID-19 pandemic.

Q. PLEASE DESCRIBE THE LATEST TRENDS IN COAL AND NATURAL GAS MARKET CONDITIONS.

A. Coal markets continue to be distressed and there has been increased market volatility due to a number of factors, including: (1) deteriorated financial health of coal suppliers due to declining demand for coal stemming from accelerated coal retirements and overall declines in coal generation demand resulting from COVID-19; (2) continued abundant natural gas supply and storage resulting in lower natural gas prices, which has lowered overall domestic coal demand; (3) uncertainty around proposed, imposed, and stayed U.S. Environmental Protection Agency regulations for power plants; (4) changing demand in global markets for both steam and metallurgical coal; (5) uncertainty surrounding regulations for mining operations; and, (6) corrections in production levels in an attempt to bring coal supply in balance with demand.

With respect to natural gas, the nation's natural gas supply has grown significantly over the last several years and producers continue to enhance production techniques, increase efficiencies, and lower production costs. Natural gas prices are reflective of the dynamics between supply and demand factors, and in the short term, such dynamics are influenced primarily by seasonal weather demand and overall storage inventory balances. While there continues to be growth in the natural gas production infrastructure to serve increased market demand, pipeline infrastructure permitting and regulatory process approval efforts are challenged due to increased reviews and interventions, which can delay and change planned pipeline construction and commissioning timing. Specificially, cancellation of the Atlantic Coast Pipeline which was terminated July 5, 2020 will limit the Company's access to low cost natural gas resources.

Over the longer-term planning horizon, natural gas supply is projected to continue to increase along with the needed pipeline infrastructure to move the growing supply to meet demand related to power generation, liquefied natural gas exports and pipeline exports to Mexico.

Q. WHAT ARE THE PROJECTED COAL AND NATURAL GAS CONSUMPTIONS AND COSTS FOR THE BILLING PERIOD?

A. DEC's current coal burn projection for the billing period is 8.0 million tons compared to 7.2 million tons consumed during the review period. DEC's billing period projections for coal generation may be impacted due to changes from, but not limited to, the following factors: (1) delivered natural gas prices versus the average delivered cost of coal; (2) volatile power prices; and (3) electric demand. Combining coal and transportation costs, DEC projects average delivered coal costs of approximately $67.49 per ton for the billing period compared to $85.33 per ton in the review period. This includes an average total projected transportation cost of $26.02 per ton for the billing period, compared to $29.92 per ton in the review period. The lower projected cost is due, in part, to the rail transportation contracts which went into effect in March 2019. This projected average delivered coal cost, however, is subject to change based on, but not limited to, the following factors: (1) exposure to market prices and their impact on open coal positions; (2) the amount of non-Central Appalachian coal DEC is able to consume; (3) performance of contract deliveries by suppliers and railroads, which may not occur despite DEC's strong contract compliance monitoring process; (4) changes in transportation rates; and (5) potential additional costs associated with suppliers' compliance with legal and statutory changes.

DEC's current natural gas burn projection for the billing period is approximately 152.1 million MBtu, which is an increase from the 128.5 million MBtu consumed during the review period. The net increase in DEC's overall natural gas burn projections for the billing period versus the test period is driven by the inclusion of natural gas generation at Belews Creek, and Marshall Units 3 & 4 as a result of the dual fuel conversions being commercially available over the course of the billing period, combined with increased generation output from the Clemson CHP and Lincoln CT projects. The current average forward Henry Hub price for the billing period is $2.60 per million MBtu, compared to $2.17 per million MBtu in the review period. Projected burn volumes will vary based on factors such as, but not limited to, changes in commodity prices and weather driven demand.

Q. WHAT STEPS IS DEC TAKING TO MANAGE PORTFOLIO FUEL COSTS?

A. The Company continues to maintain a comprehensive coal and natural gas procurement strategy that has proven successful over the years in limiting average annual fuel price changes while actively managing the dynamic demands of its fossil fuel generation fleet in a reliable and cost-effective manner. With respect to coal procurement, the Company's procurement strategy includes (1) having an appropriate mix of contract and spot purchases for coal; (2) staggering coal contract expirations in order to limit exposure to market price changes; and (3) diversifying coal sourcing as economics warrant, as well as working with coal suppliers to incorporate additional flexibility into their supply contracts. The Company conducts spot market solicitations throughout the year to supplement term contract purchases, taking into account changes in projected coal burns and existing coal inventory levels.

The Company has implemented natural gas procurement practices that include periodic Request for Proposals and shorter-term market engagement activities to procure and actively manage a reliable, flexible, diverse, and competitively priced natural gas supply. These procurement practices include contracting for volumetric optionality in order to provide flexibility in responding to changes in forecasted fuel consumption. DEC continues to maintain a short-term natural gas hedging plan to manage fuel cost risk for customers via a disciplined, structured execution approach. DEC continues to monitor and make adjustments as necessary to its natural gas hedging program. In order to better mitigate cost risks for its customers, the Company recommends extending its financial hedging activities for a lower percentage in rolling years four and five.

Lastly, DEC procures long-term firm interstate and intrastate transportation to provide natural gas to their generating facilities. Given the Company's limited amount of contracted firm interstate transportation, the Company participates in the capacity release market to purchase shorter term firm interstate pipeline capacity as available. The Company's firm transport ("FT") provides the underlying framework for the Company to manage the natural gas supply needed for reliable cost-effective generation. First, it allows the Company access to lower cost natural gas supply from Transco Zone 3 and Zone 4 and the ability to transport it to Zone 5 for delivery to the Carolinas' generation fleet. Second, it allows the Company to manage intraday supply adjustments on the pipeline through injections or withdrawals of natural gas supply from storage, including on weekends and holidays when the gas markets are closed. Third, it allows the Company to mitigate imbalance penalties associated with Transco

pipeline restrictions. The Company's customers receive the benefit of each of these aspects of the Company's FT: access to lower cost gas supply, intraday supply adjustments at minimal cost, and mitigation of punitive pipeline imbalance penalties.

Q. CAN THE COMPANY MONETIZE UNUSED GAS CAPACITY ON DAYS WHEN THE SYSTEM IS NOT CONSTRAINED?

A. No. Typically, the Company does not have excess natural gas capacity on the interstate pipeline system that it can sell to third parties. However, due to demand reductions resulting from COVID-19, the Company temporarily found itself with excess capacity, which it offered into the daily capacity release market starting mid-April through May 2020 at the price of $.02 decatherms per day. The Company did not receive any offers to purchase this capacity and was unable to sell any of its offered excess capacity.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

Duke Energy Carolinas, LLC Fossil Fuel Procurement Practices

Coal

- Near and long-term coal consumption is forecasted based on inputs such as load projections, fleet maintenance and availability schedules, coal quality and cost, environmental permit and emissions considerations, projected renewable capacity, and wholesale energy imports and exports.
- Station and system inventory targets are developed to provide reliability, insulation from short-term market volatility, and sensitivity to evolving coal production and transportation conditions. Inventories are monitored continuously.
- On a continuous basis, existing purchase commitments are compared with consumption and inventory requirements to determine additional needs.
- All qualified suppliers are invited to participate in proposals to satisfy additional or contract needs.
- Spot market solicitations are conducted on an on-going basis to supplement contract purchases.
- Contracts are awarded based on the lowest evaluated offer, considering factors such as price, quality, transportation, reliability and flexibility.
- Delivered coal volume and quality are monitored against contract commitments. Coal and freight payments are calculated based on certified scale weights and coal quality analysis meeting ASTM standards as established by ASTM International.

Gas

- Near and long-term natural gas consumption is forecasted based on inputs such as load projections, commodity and emission prices, projected renewable capacity, and fleet maintenance and availability schedules.
- Physical procurement targets are developed to procure a cost effective and reliable natural gas supply.
- Over time, short-term and long-term Requests for Proposals and market solicitations are conducted with potential suppliers to procure the cost competitive, secure, and reliable natural gas supply, firm transportation, and storage capacity needed to meet forecasted gas usage.
- Short-term and spot purchases are conducted on an on-going basis to supplement term natural gas supply.
- On a continuous basis, existing purchases are compared against forecasted gas usage to ascertain additional needs.
- Natural gas transportation for the generation fleet is obtained through a mix of long term firm transportation agreements, and shorter term pipeline capacity purchases.
- A targeted percentage of the natural gas fuel price exposure is managed via a rolling 36-month structured financial natural gas hedging program.
- Through the Asset Management and Delivered Supply Agreement between Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC implemented on January 1, 2013, DEC serves as the designated Asset Manager that procures and manages the combined gas supply needs for the combined Carolinas gas fleet.

Fuel Oil

- No. 2 fuel oil is burned primarily for initiation of coal combustion (light-off at steam plants) and in combustion turbines (peaking assets).
- All No. 2 fuel oil is moved via pipeline to applicable terminals where it is then loaded on trucks for delivery into the Company's storage tanks. Because oil usage is highly variable, the Company relies on a combination of inventory, responsive suppliers with access to multiple terminals, and trucking agreements to manage its needs. Replenishment of No. 2 fuel oil inventories at the applicable plant facilities is done on an "as needed basis" and coordinated between fuel procurement and station personnel.
- Formal solicitations for supply may be conducted as needed with an emphasis on maintaining a network of reliable suppliers at a competitive market price in the region of our generating assets.

DUKE ENERGY CAROLINAS
Summary of Coal Purchases
Twelve Months Ended May 2020 & 2019
Tons

Line No.	Month	Contract (Tons)	Net Spot Purchase and Sales (Tons)	Total (Tons)
1	June 2019	647,313	140,296	787,609
2	July	692,046	77,088	769,134
3	August	732,253	115,963	848,216
4	September	469,275	204,304	673,579
5	October	471,409	231,850	703,259
6	November	397,228	239,441	636,669
7	December	560,959	202,536	763,495
8	January 2020	719,300	39,752	759,052
9	February	377,885	130,203	508,088
10	March	511,418	51,906	563,324
11	April	454,145	23,566	477,711
12	May	203,960	12,873	216,833
13	**Total** (Sum L1:L12)	**6,237,191**	**1,469,778**	**7,706,969**

Line No.	Month	Contract (Tons)	Net Spot Purchase and Sales (Tons)	Total (Tons)
14	June 2018	683,250	37,208	720,458
15	July	717,234	149,366	866,600
16	August	678,522	221,948	900,470
17	September	564,680	218,858	783,538
18	October	387,121	95,650	482,771
19	November	349,179	53,824	403,003
20	December	483,535	96,525	580,060
21	January 2019	467,830	111,868	579,698
22	February	555,624	64,276	619,900
23	March	551,679	112,937	664,616
24	April	476,648	227,914	704,562
25	May	549,400	152,538	701,938
26	**Total** (Sum L14:L25)	**6,464,702**	**1,542,912**	**8,007,614**

DUKE ENERGY CAROLINAS
Summary of Gas Purchases
Twelve Months Ended May 2020 & 2019
MBTUs

Line No.	Month	MBTUs
1	June 2019	10,195,827
2	July	12,505,061
3	August	12,104,186
4	September	12,459,839
5	October	8,409,940
6	November	5,772,711
7	December	10,423,250
8	January 2020	13,098,158
9	February	13,151,481
10	March	13,043,284
11	April	6,893,840
12	May	10,414,617
13	**Total** (Sum L1:L12)	**128,472,194**

Line No.	Month	MBTUs
14	June 2018	12,715,364
15	July	15,647,875
16	August	12,892,804
17	September	12,377,677
18	October	10,303,322
19	November	11,867,520
20	December	9,183,559
21	January 2019	11,540,233
22	February	11,895,973
23	March	8,829,116
24	April	7,309,473
25	May	12,448,810
26	**Total** (Sum L14:L25)	**137,011,726**